TRANSMITTAL SLIP	DATE
	25 May 1982
TO: NIO/Econ	
ROOM NO. 7E47	BUILDING HQS
REMARKS:	
FROM: D/OGI	
ROOM NO. 3G00	BUILDING HQS

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SECRET [redacted] 25X1

Central Intelligence Agency

DDI- 4399-82

Washington, D.C. 20505

28 MAY 1982

MEMORANDUM FOR: The Honorable Fred C. Ikle
Under Secretary of Defense for Policy

SUBJECT : West European Gas Alternatives [redacted] 25X1

1. In response to your recent conversation with Harry Rowen regarding European gas alternatives, we have prepared the attached memorandum. It summarizes some of our most recent work on development of alternative gas resources for Western Europe and is an addition to the earlier work that Harry forwarded to you. The focus here is on the timing and financial requirements of specific North Sea projects and the outlook for additional supplies of Algerian gas. [redacted] 25X1

2. If you have any questions or if we can be of further assistance, please contact [redacted] 25X1

Robert M. Gates
Deputy Director for Intelligence

Attachment:
Strategies for Development of Alternative Gas Resources, GI M 82-10112, May 82 25X1

[redacted] 25X1

[redacted]

SECRET [redacted]

25X1

SUBJECT: West European Gas Alternatives [redacted]

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OGI/ED/ [redacted] (19 May 1982)

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Central Intelligence Agency

Washington, D.C. 20505

DIRECTORATE OF INTELLIGENCE

25 May 1982

Strategies for Development of Alternative Gas Resources

Summary

Exploratory drilling over the last several years has revealed huge gas reserves in the North Sea--particularly in the Norwegian sector--which could provide sizable additional gas supplies to the European continent beginning in the 1990s and continuing well beyond the turn of the century. Nonetheless, North Sea gas development will proceed apace only if some measures are taken soon to lay the groundwork for future development. [redacted] 25X1

The gas projects under construction face high capital costs and long lead times; in turn, their profitability is extremely sensitive to interest rates. Interest rate subsidies similar to those offered in construction of the Soviet pipeline would provide a substantial incentive in speeding development of North Sea reserves. By lowering the interest rate by one percentage point on a $2.1 billion investment in a North Sea project, for example, annual production costs would fall by $21 million, lowering unit costs by $.12 to $.15 per million Btu. Other critical factors in determining the timing and size of new North Sea projects include:

- *Government policies in Norway and the United Kingdom. UK tax policies are a serious deterrent to development of small fields. Norway's petroleum taxes are also high, but development is further slowed by short drilling seasons and generally cautious government policies.*

- *Market prospects. An unprecedented decline in West European gas consumption over the last two years has clouded the outlook for the future size of the European gas market. Present uncertainties could cause North Sea producers to hesitate before launching new projects especially in view of the possibility of being undercut by cheaper Soviet or Algerian gas.* 25X1

[redacted]

[redacted] GI M 82-10112 25X1

Relative to North Sea costs, the wellhead cost of producing Algerian gas is extremely low. Algeria's demands for crude oil parity, however, will probably keep the price of its gas high. With additional compressors, the existing Transmediterranean pipeline could carry up to 6 bcm in addition to existing commitments. On the other hand, recently discovered technical problems in producing gas from Algeria's largest gas field may mean that little additional gas will be available in the 1980s. Additional volumes are likely to become available in the 1990s which could support another Transmediterranean pipeline to either Italy or Spain. [redacted] 25X1

This memorandum was prepared by [redacted] Energy Markets Branch, Office of Global Issues. The information contained herein is updated to 15 May 1982. This paper was coordinated with EURA. Comments may be directed to [redacted] Chief, Energy Markets Branch, [redacted] 25X1 25X1 25X1

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Strategies for Development of Alternative Gas Resources

Block 31/2--Troll

Norway's Troll gasfield is believed to contain between 1.4 and 2.0 trillion cubic meters of gas--roughly the size of the Netherland's Groningen field. The Troll structure is located in blocks 31/2, 31/3, 31/5, and 31/6 of which only 31/2 has been awarded and drilled by operator Shell. Norway's new conservative government has reviewed proposals for allocating the remaining blocks and is expected to award blocks 31/3 and 31/6 to Norsk Hydro. Statoil is likely to be appointed operator on block 31/5 and granted permission to exercise its option to take over as operator on 31/2. The two Norwegian companies are gearing up for this and other major development projects, but still must rely on the major oil companies for technical expertise in some areas. [redacted] 25X1

In addition to its gas reserves, the Troll structure is believed to contain oil reserves of up to 2 billion barrels. Since the oil lies in a relatively thin layer below the gas reservoir, however, it is not yet clear that it can be economically produced. According to Shell, a preliminary proposal for developing Troll's oil indicated unit costs of $35,000 per peak daily barrel of capacity and a maximum real rate of return of six to eight percent. The oil layer in the western part of the field is about 60 feet thick, and might be commercially producible. Further to the east, the oil layer varies in thickness from 0 to 30 feet and is probably not recoverable. Shell plans to drill two appraisals of the oil zone this year plus a further exploration well. [redacted] 25X1

Field Development

Shell is moving smoothly toward a development plan for 31/2 and expects to make a formal declaration of commerciality for the field by early 1983. It has already awarded contracts to six companies for feasibility studies on the main development alternatives, some of which are so far untried in the North Sea. Both fixed steel platform and concrete gravity platform concepts are being evaluated and, given the water depth of 1,000 feet and the shallow broad reservoir, subsea production techniques are bound to play a significant role in development. Feasibility studies are currently underway to evaluate:

- o the Condeep T300 concrete platform (Norwegian Contractors);

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- o a tension leg platform (VO offshore);

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[redacted]

[redacted] 25X1

- a steel tripod platform (Heerema);
- a multi-well subsea production template (Kvaerner Engineering and Can Ocean);
- alternative riser configurations--the conduit that delivers oil or gas from the wellhead to the surface (Kongsberg Engineering); and
- offshore gas, oil and NGL treatment facilities (S.H. Landes). [redacted] 25X1

Because new technologies must be employed, it is difficult to estimate development costs before detailed feasibility studies are completed. The Condeep platform is a gravity based platform with three concrete legs joined below the waterline and a single leg supporting the deck. [redacted] 25X1 25X1

[redacted]

Pipeline Alternatives-Scenario A

The quickest way of initiating gas deliveries from Troll would entail linking the field to the existing Frigg pipeline to the United Kingdom. In return, comparable amounts of gas from the UK would be delivered to the continent via a new pipeline in the southern sector of the North Sea. A link to the existing Frigg line might allow deliveries to begin in the early 1990s and would probably cost less than $500 million. Production from Frigg is expected to drop to nearly zero by 1992, leaving spare pipeline capacity of about 20 bcm per year. Moreover, with additional compressors the capacity of the Frigg line could be expanded to 27 bcm per year. [redacted] 25X1

Although this alternative would probably allow a lower delivered cost for gas, it has some drawbacks for the Norwegians.

- An agreement for the gas swap would have to be reached with the United Kingdom.

[redacted] 25X1

- Deliveries would be constrained by the capacity of the Frigg system and the volume of gas the British are willing to swap. [redacted] 25X1

In the mid to late 1990s, spare capacity should become available in the Statpipe system which will be linked to the West German gas grid. At that time, gas from Troll could be delivered to Europe via a link to Statpipe. The Statpipe system has a total planned capacity of 17 bcm including the present Ekofisk to Emden line and could be expanded to deliver about 20 bcm with additional compressors. [redacted] 25X1

Pipeline Alternatives-Scenario B

Norway could build a new gas trunkline capable of delivering 30 to 40 bcm directly to the continent. While this alternative would free the Norwegians from the constraints mentioned above, it would probably entail capital costs of more than $3 billion and could take 2 to 3 years longer than building the link to the Frigg system. The new trunkline would be more than 800 miles long and would require more than 800,000 tons of steel. [redacted] 25X1

[redacted] 25X1

Triangular Gas Deal

Using the United Kingdom as a conduit for delivering Norwegian gas to the continent could save both time and money compared to the alternative of building a major new trunkline. Norwegian gas delivered to Scotland could be swapped with UK gas in the Southern Basin, providing at least 10 to 15 bcm annually. [redacted] 25X1

In the near term, Norway's Sleipner field--with reserves in excess of 200 million cubic meters--is the most logical field to link to the United Kingdom. Exploratory assessment of the field is nearly completed and a development decision will be made in the next one to two years. Moreover, the field has a high concentration of carbon dioxide in the gas and will probably require a separate distribution system. Because several small fields in the UK sector have a similar problem with carbon dioxide content, a link to the UK would be a logical step. [redacted] 25X1

Proven gas reserves in the southern sector of the UK offshore waters are 370 bcm and substantial additional reserves remain to be proven. British tax policy is an important factor in estimating the future availability of gas from the UK. If tax policies that currently discriminate against development of relatively small fields were to be modified, the profitability of developing the numerous small gasfields in the Southern Basin could be restored. [redacted] 25X1

Field Development and Pipelines

Because the reserves of the Sleipner complex are distributed among seven reservoirs, at least five platforms would be required to fully exploit the field. The field is located in about 400 feet of water and largely will employ technologies previously tested in North Sea waters. Energy Advice has estimated the capital costs of field development at $6-7 billion. Including operating and transportion costs (presumably via pipeline to the UK), the cost of gas delivered to the United Kingdom was estimated at $3.50 per million BTU. [redacted] 25X1

[redacted] 25X1

[redacted] 25X1

Tromsa

The Tromsa area off Norway's northern coast has probable reserves of 140-250 billion cubic meters and is believed to have considerable potential reserves in addition. The gas contains 5.7 percent carbon dioxide, a relatively high level but probably not high enough to require special processing. Development is constrained by a short drilling season of only five months and substantial additional drilling must still be done before any major development decisions are in order. [redacted]

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[redacted]

[redacted] 25X1

Algeria

Algeria's ability to supply additional gas in the 1980s is questionable because of high price demands and technical problems with gas cycling programs and field development. Increased requirements for the gas reinjection program around the Hassi R'Mel field are likely to force a cutback of available export supplies beginning in early 1983. Even with an accelerated development program in the southern fields which could supply gas beginning in 1984, Algeria could still fall short of meeting its domestic and export commitments. Algeria is unlikely to meet the shortfall by cutting back on gas reinjection because the value of the resultant loss in condensate and LPG production probably would exceed the value of gas sales. With the completion of the recycling programs in the 1990s, 70 bcm of gas would be made available to meet rising domestic consumption and support additional exports projects. Projects that have been considered are:

- o 6 bcm expansion of Algeria-Italy pipeline with additional compressor station and single Trans-med pipeline;
- o 18 bcm parallel Algeria-Italy pipeline; and
- o 4-20 bcm pipeline to Spain.

The feasibility of pipeline crossings to Italy has already been demonstrated. A pipeline to Spain would be both longer and deeper, but a preliminary feasibility study by an international engineering company has concluded that the additional problems are by no means insurmountable. In addition, overall costs of another transmediterranean pipeline would still probably be less than the cost of a major new trunkline in the North Sea. It is likely, however, that no more than an additional 20 bcm will be exported, unless sizable new reserves are found or domestic consumption falls short of expected levels. Given low gas development costs, the Algerians could probably lower gas prices in the 1990s in order to secure a market for the additional gas. Unless Algeria reduces its price demands and demonstrates its reliability as a supplier--something it may be unwilling to do in the 1980s as gas commitments exceed available supplies--additional sales are unlikely.

Costs of Producing and Delivering Algerian Gas via Existing Facilities
($ per million BTU)

	Pipeline	LNG
Field production costs	.75	.75
Processing and transmission costs	.83	2.00
Total Delivered Cost	1.58	2.75

[redacted] 25X1

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[redacted] 25X1